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Predicting Future Performance from Reservoir Management Cycling

K. K. Bloomfield
G. L. Mines
Idaho National Engineering and Environmental Laboratory

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Cycling, Model, Sustainability

ABSTRACT
Cycling refers to varying operating modes in response to changes in system load requirements. Selling electricity in the volatile energy market with its uncertain rates of return demands positive design control over all equipment and reservoir systems to ensure formal qualifications, marketability, and dispatch responsiveness. This study models a producing Basin and Range geothermal system by matching a historical temperature decline, which is then used to forward model resource temperature decline under base load and a cycling operation. The resulting resource decline scenarios are used to forecast both electrical production capacity and revenues, using historical energy prices and a typical annual ambient temperature profile. This approach improves understanding of how to increase plant revenues by using cycling to take advantage of changes in on- and off-peak power prices. The study shows that cycling operations can offset temperature decline of the resource, sustaining capacity over the life of the plant.

INTRODUCTION

This study presents scenarios for operating a geothermal resource and power plant that maximize profitability and sustain capacity over plant life. The study offers the geothermal industry an additional information tool: an integrated approach to optimize resource production and economic benefit. The approach analyzes data to determine if cycling operations are appropriate for resource, surface facilities, and power sales agreements.

Surface facilities are the physical link to the reservoir. The facility does everything that applies to the reservoir, including well location, pumping, injecting, and power production. Proper design of the facility, as well as maintenance and operation, has a profound effect on profitability. The facility must be capable of following the reservoir management plan and must not convert energy from the geothermal fluid inefficiently nor expend unnecessary capital costs by over design.

The roots of geothermal reservoir management are found in reservoir engineering, which taken in the broadest sense, is the technology that deals with the movement of fluids into and through the geological formations that heat them, their subsequent extraction from the reservoir by means of wells, and the power plants where its thermal energy is converted to electricity and sold as product. Reservoir management and reservoir engineering, however, are not identical. Reservoir management implies the existence of goals toward which the reservoir technology is directed. The technological implementations used to achieve these goals may be specific to individual reservoirs.

APPROACH

This work combines the use of both reservoir and energy conversion system simulators to enhance the decision-making process for the combined operation of a resource and its geothermal power plant. The paper describes how we evaluated whether cycling the geothermal resource could reduce the onset of cooling of the resource without reducing power generation revenues. Our approach was to first develop production profiles for different operating scenarios by using a numerical reservoir simulator, which is the most comprehensive performance prediction tool. Reservoir simulator models permit inclusion of detailed reservoir descriptions, which result in more accurate predictions associated with the different operating scenarios. Plant performance can then be modeled for these production scenarios using steady-state thermodynamic process simulators. This modeling identifies plant operating parameters, which optimize power production and revenue streams.

To evaluate the impact of cycling, reservoir, production, and economic parameters must either be known or assumed. Because cycling may require capital investment, such as variable speed drives for the brine pumps (Bloomfield and Mines), it is imperative that a detailed reservoir and economic analysis be conducted in order to optimize the fluid production scenario and maximize revenues.

MODELING APPROACH

We modeled the geothermal reservoir in three dimensions using the commercially available numerical reservoir simulator TETRAD. The areal size of the model was 3680 by 2630 feet. It included well surface locations of 14 production and 8 injection wells, surface elevation using sea level as a datum, depth to top of reservoir, initial temperatures, daily mass production, and brine temperature entering the plant. We determined the reservoir to have a uniform thickness of 2200 feet, using the estimated thickness of the production zone, underlying injection zone, and depth of the injector, which are the producing formations of the geothermal liquids. The study area was modeled horizontally by a 20 by 20 grid. The vertical grid consists of nine layers of varying thickness. Large blocks were used in single-phase regions, and smaller blocks were used for the production layers in case a two-phase region formed during production. This was to reduce the convergence time of the simulator.

When reservoir behavior is dominated by water influx, the reservoir model should also be dominated by detailed modeling of aquifers, which are represented using several outside cells or segments. The model has aquifers on all sides of the domain and was allowed to default to the properties of the grid block to which they were attached. Initially, the aquifers were set to be steady state using the Carter-Tracy equation. The permeability of the steady-state aquifers was too high because temperature and pressure matches could not be obtained and, when the model had some brief curtailments of fluid production, the model would fill the two-phase areas around the producers full of water, which seemed unrealistic. The only way to overcome this anomaly was to use infinite acting aquifers. However, when using them, we could not obtain a temperature match. In order to obtain the match, only one steady-state aquifer was used in the mix of aquifers.

By adjusting aquifer flux, it was possible to match the historically produced fluid temperature and flow rate. The model was then forward modeled under base load conditions for 10 years. The base load flow rate for the plant was 2,295 klbs/hr for a plant design of 16 Mwe net generation output. After modeling the base, the same model was forward modeled under cycling conditions. For the off-peak period, 8 hr/day was selected at 75% of the base load flow rate. For the on-peak period, 16 hr/day was selected at 110% of the base load flow rate. The off-peak hours were from midnight to 0800 hr; the on-peak hours were the remainder of the day. The base load forward model results were compared to the cycling model to establish any differences in produced fluid temperatures.

The thermodynamic analysis of plant performance was modeled using the commercially available software ASPEN PLUS. The modeled facility was an air-cooled binary power plant. The modeled plant included turbines, heat exchangers, air cooled condensers, working fluid pumps, and auxiliary processes, as well as equations of state that allow properties to be predicted for the various plant fluids. Each component is modeled so that its performance matches either vendor-supplied performance data or operating data. This matching of component performance, as well as plant power output, was used to validate the model. After validation, the model was used to predict the optimized performance of the plant in response to variation in the ambient temperature and changes in resource productivity (flow and temperature). Results were used to develop correlations for plant performance as functions of the ambient temperature and brine temperature and flowrate. These correlations were then used to evaluate the overall thermo-economics of cycling.

RESULTS

We used the reservoir model simulation to match the production data from the start of 1991 through 1998. Available temperature history for the plant was only available from 1991 through April 1995. Figure 1 shows the results of the temperature history match through April 1995. In generating the match, we combined the well production data with the flowrate and temperature of fluids entering the plant to establish the historical resource production. The match shown in Figure 1 was obtained by adjusting the permeability of the aquifers attached to the model. The simulated temperature in 1998 (not shown in the figure) was 320^{o}F.

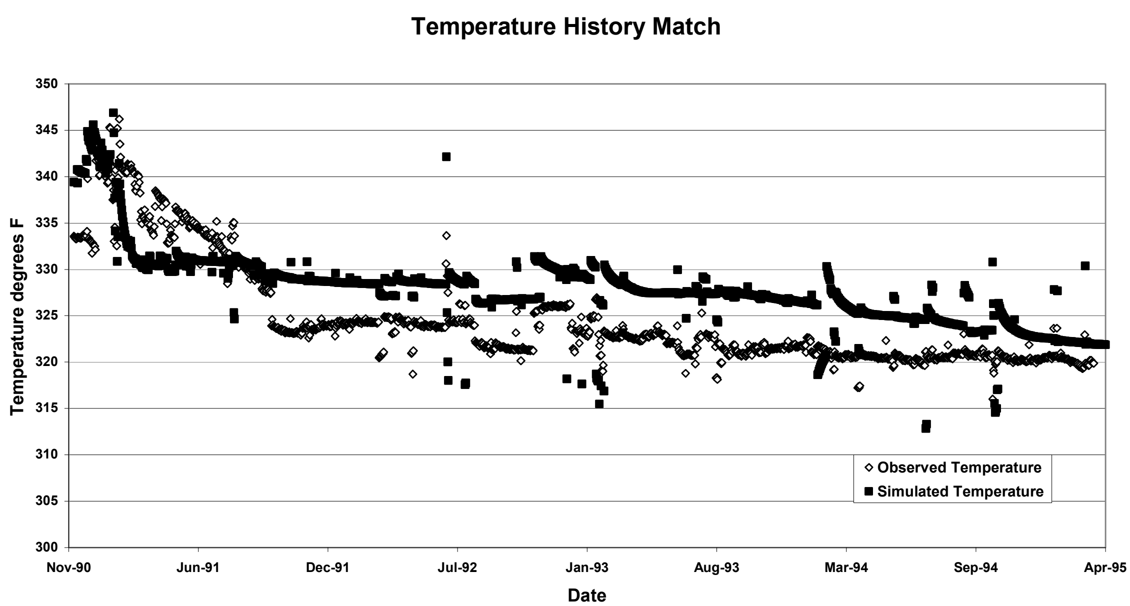

Figure 1. Temperature history match.

After we obtained the temperature match, we constructed a forward model for both the base load and cycling modes of operation. The base load operating mode was forward modeled, from assumptions from the history match model of the most probable operation of producers and injectors. Using the assumed operation of the producers and injectors, we then increased and decreased production from the injectors and producers by the same percentage to simulate a cycling mode of operation. The simulation results indicate that if the fluid withdrawal from the resource is reduced by 3%, the resource will recover 2°F over an initial period of 12 months. After this recovery period, the resource temperature will decline at about the same rate as it would have from the base load operations (Figure 2). The delay in cooling from the different operation is approximately 48 months. The significance of this delay in cooling can be considerable, as plant output approaches an economic limit before makeup wells are needed to maintain plant capacity. The deferred cost of drilling and completing makeup wells may by itself justify the additional equipment costs to provide the ability to cycle the power plant. The increment in operating cost associated with this added equipment is outside the scope of this study.

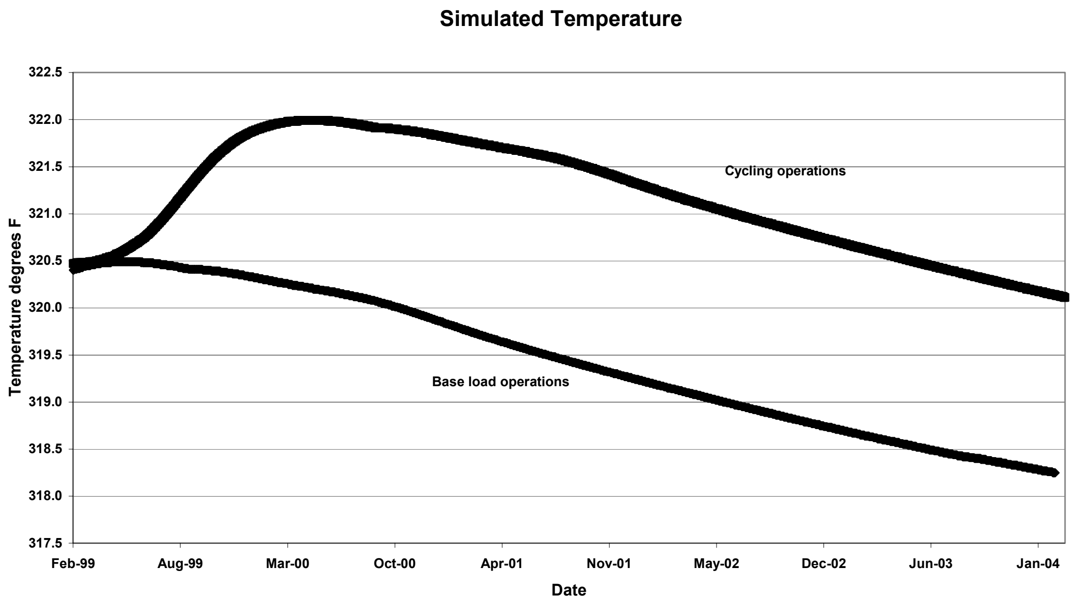

Figure 2. Simulated temperature recovery of resource comparison of base load versus cycling operations.

Plant output was modeled using historical hourly temperatures for a 1-year period and the same brine temperature of 320°F for both operating scenarios. The revenues were then calculated using historical California energy prices for the period of May 2001 though April 2002. This period was chosen because it showed some stability after the energy crisis in California. Table 1 presents the monthly revenues of the different operating scenarios.

Table 1. Monthly revenues of base load versus cycling operations.

Month	Base Load Deregulated Power Prices	Cycling Deregulated Power Prices	Difference
May 2001	$676,136	$688,645	$12,510
June 2001	$519,883	$521,116	$1,233
July 2001	$316,348	$318,917	$2,569
August 2001	$213,282	$213,637	$355
September 2001	$219,139	$223,504	$4,365
October 2001	$222,808	$240,018	$17,210
November 2001	$319,478	$359,760	$40,283
December 2001	$309,495	$379,949	$70,454
January 2002	$214,840	$250,312	$35,472
February 2002	$192,325	$213,124	$20,800
March 2002	$296,476	$324,957	$28,481
April 2002	$233,757	$249,440	$15,683
Total	$3,733,967	$3,983,379	$249,415

The increased revenues from cycling operations were $250K, which increased revenues 14% for the year studied. These results suggest that the largest benefit would have occurred during the colder winter months. This is because the relative impact of the flow reduction on plant power production was smaller at the colder temperatures during off peak hours.

We also forecasted plant output and revenues to capture the recovery in temperature and delay in cooling from cycling operations, applying the forecast to the 12-month temperature recovery and the 48-month delay in cooling. Figure 3 shows the forecasted results, which reflect the higher power conversion efficiency for the hotter geothermal fluids associated with the cycling due to temperature recovery and delayed cooling. It shows the better power conversion efficiency for the hotter fluids, owing to the temperature recovery of the resource as a result of cycling operations. The cumulative impact on cash flow for the two operating scenarios (Figure 4) results in a $1.6MM undiscounted increase in cash flow for the 5-year period.

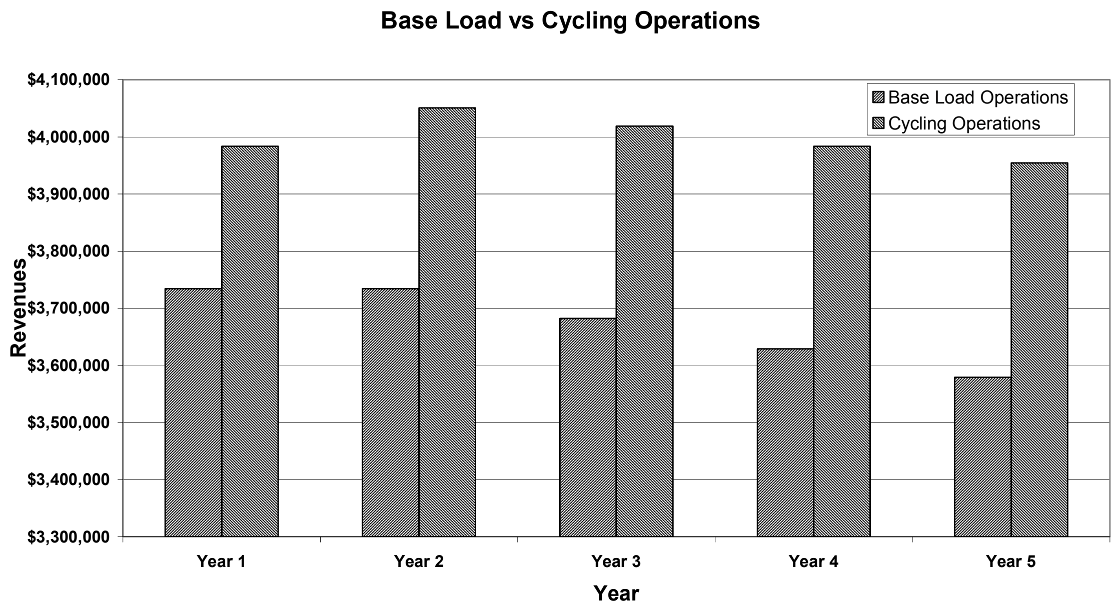

Figure 3. Yearly comparison of revenues.

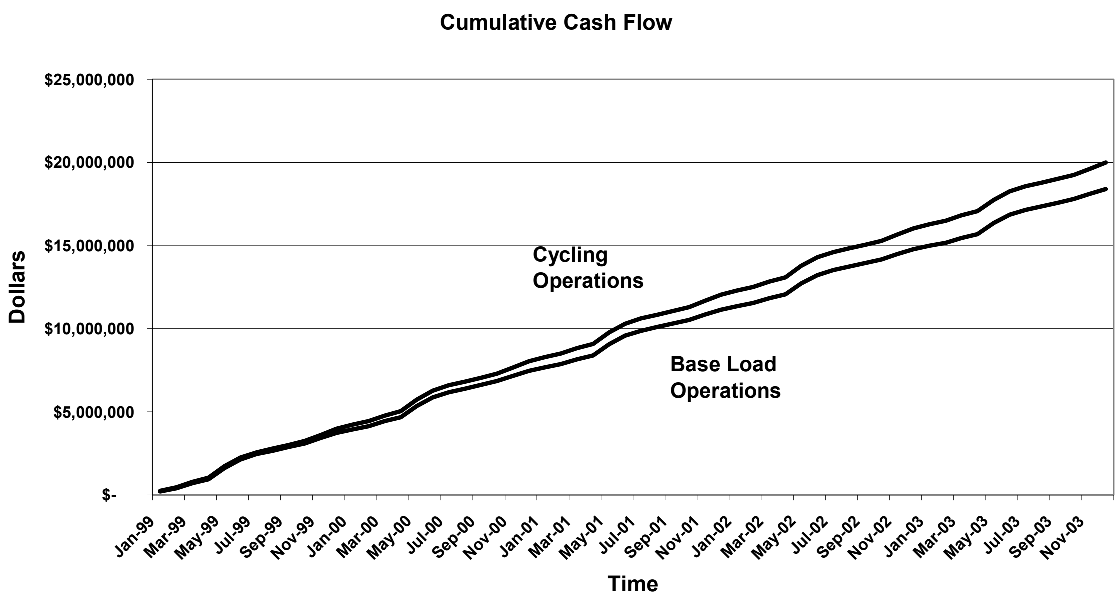

Figure 4. Cumulative cash flow base load versus cycling operations.

CONCLUSION

Coupling the reservoir and power plant models to predict their combined performance response is a very useful, if not necessary, in performing the economic analysis used to make business decisions to maximize project revenues and profits. This investigation illustrates the benefit of quantifying the cost effectiveness of cycling geothermal resources to increase revenues under a competitive or deregulated market pricing structure. The study concludes that by cycling this particular 16-Mwe plant and resource, $250K, or14%, increased revenue can be achieved per year, with 3% less fluid extracted from the resource. For the resource modeled, this reduced production rate resulted in an initial recovery of the resource temperature and delayed the subsequent temperature decline by about 4 years. The hotter fluids produced under this cycling scenario yield a relative increase in future power generation revenues from the plant while delaying the investment (drilling additional wells) necessary to recover power production capacity. The economic benefits identified by this study used power prices from the deregulated power market for base load and cycling operations. These benefits may not be realized by geothermal power producers that receive short-range avoided cost for their power (their original contract), not the prices available from the deregulated power market in California. However, any new geothermal power plants constructed and marketing their power within a deregulated power market should consider design in the wells and power plant that will allow them to capture the opportunities of the elevated power prices during on-peak power demands.

ACKNOWLEDGMENTS

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